UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Avista Corporation;	)	
The Montana Power Company;	)	
Nevada Power Company;	)	Docket No. RT01-15-____
Portland General Electric Company; and	)	
Sierra Pacific Power Company	)	Docket No. ER02-___-000
	)	
TransConnect, LLC	)	(Not Consolidated)
	)	

DIRECT TESTIMONY

OF

DR. DAVID B. PATTON

On behalf of

TRANSCONNECT, LLC

November 1, 2001

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I. INTRODUCTION AND SUMMARY

A. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is David B. Patton. I am an economist and President of Potomac Economics. Our offices are located at 4029 Ridge Top Road, Fairfax, VA 22030. Potomac Economics is a firm specializing in expert economic analysis and strategic consulting.

Q. PLEASE STATE YOUR EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have worked as an energy economist for twelve years, focusing primarily on the electric utility and natural gas industries. I have provided strategic advice, analysis and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. In addition, I am the Market Advisor for the New York ISO and ISO New England, Inc. In these matters, I am responsible for assisting in the implementation of a monitoring plan to identify and remedy market design flaws and abuses of market power. I have also advised other existing and prospective ISOs on transmission pricing, congestion management, and market power issues.

I have provided expert testimony and analysis regarding competitive issues in a number of mergers and market-based pricing cases before the Federal Energy Regulatory Commission, state regulatory commissions, and the U.S. Department of Justice.

Prior to my experience as a consultant, I served as a Senior Economist in the Office of

Economic Policy at the Federal Energy Regulatory Commission ("Commission"), advising the Commission on a variety of policy issues including transmission pricing and open access policies and electric utility merger policies. As a member of the Commission's advisory staff, I worked on policies in Order No. 888, particularly on issues related to power pool restructuring, independent system operators, and functional unbundling.[1] I also analyzed the competitive characteristics of alternative transmission pricing and electricity auctions proposed by independent system operators ("ISOs"). I also provided expert testimony and advice on a number of mergers and advised the Commission on the analytic framework described in the Merger Policy Statement.

Before joining the Commission, I worked in the Office of Policy, Planning and Analysis and the Office of Energy Efficiency and Renewable Energy at the U.S. Department of Energy. During this time, I helped to develop policies related to investment in oil and gas exploration, electric utility demand-side management, development of renewable energy technologies for electric generation, residential and commercial energy efficiency, and the deployment of new energy technologies. This work included the development of policies in President Bush's National Energy Strategy and the Energy Policy Act of 1992.

I hold a Ph.D. in Economics and a M.A. in Economics from George Mason University, and a B.A. in Economics with a minor in Mathematics from New Mexico State University. For additional information, my resume is attached as Exhibit TC-5.

[1] *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs. ¶ 31,036 (1996).

B. PURPOSE AND SUMMARY OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked to address the various ratemaking issues associated with rate proposals in the context of the formation of TransConnect. In particular, in accordance with principles that satisfy the Commission's Order 2000, I have been asked (1) to describe and assess the incentive pricing proposal to promote efficient operation of the transmission network; (2) to assist in developing a pricing structure for new transmission investment that will encourage efficient expansion of the system; and (3) to consider the overall costs and benefits of the proposal.

Q. PLEASE DESCRIBE TRANSCONNECT.

A. TransConnect is a proposed stand-alone transmission business to be formed through the consolidation of the transmission assets of Avista Corporation, Montana Power Company, Nevada Power Company, Portland General Electric Company, and Sierra Pacific Power Company. Certain members of TransConnect, namely, Nevada Power Company, Portland General Electric Company, and Sierra Pacific Power Company are sponsoring this rate filing in an effort to respond to the various requirements and incentives in the Commission's Order on Regional Transmission Organizations ("RTOs") -- Order No. 2000.[2] Herein, this subgroup of TransConnect members will be referred to as "the Applicants". The non-Applicant TransConnect members, *viz.*, Avista

[2] *Regional Transmission Organizations*, Order No. 2000, December 20, 1999, 89 FERC ¶ 61,285.

Corporation and The Montana Power Company, will be TransConnect members but are not seeking the various transmission rates and policies proposed in the filing at this time. TransConnect will operate as a single transmission entity within a larger RTO structure. Currently, TransConnect is proposing to participate in the formation of RTO West. RTO West includes, in addition to the TransConnect members, B.C. Hydro, Bonneville Power Administration, Idaho Power Company, PacifiCorp, and Puget Sound Energy, Inc. TransConnect and RTO West made initial, "Stage 1", filings under Order 2000 in October. These filings primarily addressed issues of governance and scope. While the Commission provided guidance in response to the October filings, final approval has been deferred pending resolution of outstanding issues, including transmission ratemaking issues which are the subject of my testimony.

Q. HOW DO THE APPLICANTS PROPOSE TO CHARGE FOR TRANSMISSION SERVICE ON THEIR SYSTEMS?

A. The Applicants propose to offer transmission service based on a "license-plate" rate structure. License-plate rates attach a single transmission charge for the use of multiple transmission systems. The rate for use of the multiple system under license plate rates is based on the single rate applicable to the location of the electrical load. This rate treatment is typical in cases where a single-system rate is developed for a combination of transmission systems. One of its primary virtues from a ratemaking perspective lies in avoiding the difficult issue of equalizing the cost of service across systems that have varying embedded costs. From a market perspective, the single-system rate creates a level playing field for suppliers by eliminating multiple transmission charges (i.e., pancaked rates) that can place some suppliers at a competitive disadvantage. Because the most distant suppliers would generally be subject to the largest pancaked rates, implementing license-plate rates will broaden the area within which generation owners may effectively compete to sell power.

Q. HOW DO THE APPLICANTS PROPOSE TO DESIGN THEIR RATES?

A. Each of the Applicants' systems are proposed to be treated as a separate "zone," each having a transmission rate based on the specific cost-of-service of that utility's transmission system. Similarly, RTO West will establish separate rates for the zones of other RTO West members based on their revenue requirements, although the rate issues presented herein apply only to the Applicants. Therefore, the entire RTO West will charge only the license plate rate corresponding to the zone of delivery for all transactions within the RTO region. This will create a level playing field for suppliers throughout the region because all suppliers will incur the same transmission charge when competing for sales to given load.

Q. WHAT ARE THE RATEMAKING INNOVATIONS PROPOSED BY THE APPLICANTS?

A. Beside proposing transmission rates that eliminate having to pay multiple charges for regional transactions, the Applicants are proposing three ratemaking innovations in accordance with guidance provided by the Commission in Order 2000.

First, a rate cap is proposed that establishes a maximum rate for transmission service that will allow the Applicants to charge any rate up to but not exceeding the cap. This cap will be subject to an annual adjustment based on indexed changes in transmission Operation & Maintenance ("O&M") costs. To preserve critical investment incentives, rates may also change during the rate period if new investment is sufficiently high that net transmission plant increases. The rate cap will also reflect savings in Administrative and General ("A&G") expenses that are expected as a result of the consolidation of the Applicants' operations. This sharing will be accomplished by making annual adjustments to the cap to reflect the actual savings in A&G expenses.

Second, the proposal is designed to encourage efficient investment in transmission facilities by allowing investors to realize the market value of new capability that they add to the system. This is done by giving investors Firm Transmission Rights to transmission capability created as a result of their investments and by subsequently allowing these rights to be traded. This "market-based" approach to investing and pricing will lead to a more complete financial instruments that will aid in congestion management.

Third, the proposed rates incorporate a higher return on equity for certain new transmission investments that would not be subject to the market-based provisions. This provision is intended to ensure that transmission owners have sufficient incentives to expand and reinforce the system.

The rate cap period will be a five-year period beginning at the time when rates proposed herein become effective. For the purposes of illustrating various effects of the rate proposals, the rate cap period is assumed to begin January 2002. None of the qualitative conclusions are affected, however, if the rate cap period starts at a later date.

Q. PLEASE DESCRIBE THE APPLICANTS' RATE PLAN.

A. Just like the current tariff rates for each of the individual Applicants, the Applicants' proposed "zonal" rates will consist of a single, per-kW charge. For the purposes of the incentive rate analysis, it is useful to view this rate as having three main cost components: O&M expenses; A&G expenses; and all other costs (a category that basically accounts for all capital costs).

Q. PLEASE DESCRIBE THE APPLICANTS' RATE PLAN CONCERNING THE O&M COMPONENT OF COSTS.

A. The Applicants' per-kW rates will be capped at the current cost of service but the cap will be subject to annual changes as a result of indexed O&M cost changes.[3] The method of changing the O&M cost component is modeled after a form of rate cap structure commonly referred to as an "RPI – X" structure, having been proposed originally by S.C. Littlechild for British Telecom when it was privatized in 1984.[4] In that case, the rates were adjusted each year by the difference between the Retail Price Index ("RPI") and an assumed productivity factor ("X"). The RPI, a general measure of inflation in the U.K., accounted for the inflation in the total costs of production while the X provided a guaranteed reduction of the rate for consumers.

Q. WHAT IS THE ECONOMIC BENEFIT OF A RATE CAP STRUCTURE?

A. The economic benefit of a rate cap structure is that it provides strong incentives for the regulated company to reduce its costs. This is because capped rates are independent of the company's actions – thus, any cost savings achieved by the company will increase the company's profits by the same amount.

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3 Because the Applicants' transmission rates are per-kW charges that include both O&M and non-O&M costs, the rate cap will be adjusted to reflect changes only in O&M costs. As an example, consider that the current cost-of service is 12% O&M costs. If indexed O&M costs increase by 10%, then the total cap would increase by 1.2%.

4 See Regulation of British Telecommunications' Profitability, Report to the Secretary of State, Department of Industry, London (February 1983).

Q. WHAT ARE THE IMPORTANT CONSIDERATIONS IN CHOOSING THE COST INDEX?

A. The important considerations that should govern the choice of the cost index under an RPI-X rate structure are that the inflation index (1) should be well correlated with the costs being recovered by the rate and (2) should not be influenced by the regulated company. A general inflation index meets the latter consideration since the actions of the Applicants would have no effect on such an index.

With regard to the first consideration, I have conducted an empirical analysis indicating that the Consumer Price Index ("CPI") has closely tracked historical transmission O&M costs increases. Accordingly, the CPI would be an appropriate performance-based rate index, accounting for historical cost increases under the current industry structure.

In order to share with customers cost savings that may be achieved by the Applicants, the proposal includes an "X" value equal to 0.5%.

Q. WHAT INCENTIVES ARE PROPOSED RELATED TO ADMINISTRATIVE AND GENERAL EXPENSES?

A. In contrast to reductions in O&M expenses that may be achieved over time as efficiency improvements are realized, the Applicants expect significant reductions in Administrative and General expenses ("A&G") to be realized as a result of forming TransConnect. This is discussed in detail in the testimony of the Applicants' witness James Piro. It is appropriate for the Applicants to retain a portion of the savings as an incentive to undertake formation of TransConnect, given the Commission's policy objectives that are achieved through the formation of independent transmission companies. Therefore, the Applicants propose to share with customers 50% of actual A&G cost savings that result from the formation of TransConnect. As discussed in Mr. Piro's testimony, each year the Applicants will reduce rates by 50% of the achieved A&G savings as compared to the test year. Like the other components of the rate cap, this provides a strong incentive for the Applicants to attain additional A&G cost savings.

Q. IN ADDITION TO THE RATE CAP AND A&G SAVINGS, WHAT OTHER PERFORMANCE-BASED RATE INCENTIVES DO YOU RECOMMEND?

A. While the rate cap plan and treatment of A&G expenses would provide significant incentives to achieve cost reductions in the operation and maintenance of the transmission system, they do not provide the full array of economic incentives anticipated by the Commission in Order 2000. The rate cap and the treatment of A&G expenses provide strong incentives to reduce costs. But in order to increase reliability and other forms of service quality, the Applicants are proposing additional provisions to link incentives to performance benchmarks that measure reliability and service quality. These benchmarking provisions will be developed toward the end of the first year of operation with substantial input from stakeholders.

The process to implement benchmarking incentives would be initiated by the Applicants, who will present a proposed set of benchmarks after sufficient experience under TransConnect operation. During the first year of operations, the Applicants will have the opportunity to gather actual operating data to better inform proposed benchmarking provisions. The Applicants will work closely with stakeholders to modify the benchmarks and to develop the incentives and penalties associated with the benchmarks. Following this stakeholder process, the Applicants would make the decision whether to propose the benchmarking provisions to the Commission.

Q. WHAT INCENTIVES ARE THE APPLICANTS PROPOSING RELATED TO NEW INVESTMENTS IN TRANSMISSION?

A. The additional ratemaking provisions pertaining to new transmission investments include the following:

- Transmission investments made in response to requests for service by a transmission customer would be directly assigned to the customer and recovered through either a lump-sum payment or through an incremental charge to the customer. In return, the customer would receive the transmission service or Firm Transmission Rights made available by the new investment.
- Likewise, the Applicants may choose to make investments, consistent with the planning and expansion protocol, that are justified primarily by the economic value of the new capability created by the investment. These investment costs would be borne by the Applicants (i.e., directly assigned) and the Applicants would receive the Firm Transmission Rights associated with the new capability.
- Both Transmission Customers and the Applicants would have the right to assert that a portion of a directly assigned transmission investment provides system-wide benefits that would justify allocating part of the costs to all customers in the zone. Preliminary determinations on this issue would be made by the RTO.

- To the extent that new transmission investments provide system-wide benefits or are made pursuant to RTO and TransConnect planning processes, the capital costs would be recovered from all customers in the zone. However, in light of the rate cap, the Applicants will be unable to earn a return on any investments that cause net plant to increase. Hence, to avoid investment disincentives while maintaining the rate cap, the Applicants will retain the right to file for an incremental rate that allows recovery of this incremental net plant. Furthermore, to ensure adequate incentives and availability of capital to invest in these facilities, all charges associated with the new investments would be depreciated over 15 years and the return on equity would be adjusted by 200 basis points to provide adequate incentive to expand the transmission system.

Q. WILL THE APPLICANTS CONTINUE TO WORK CLOSELY WITH RTO WEST AND OTHER RTOs?

A. Yes. Any RTO to which the Applicants belong will have substantial authority in the planning and expansion process and in administering the system of Firm Transmission Rights. Therefore, the Applicants will continue to coordinate their rate-making proposals with RTO West and other relevant RTOs.

Q. DID YOU CONSIDER THE BENEFITS OF THE APPLICANTS' PROPOSALS?

A. Yes. Benefits arise from two principal sources. First, the most important source of benefits is increased competition associated with the expansion of the markets that will result from RTO formation, in which the Applicants play a key role. Based on bulk power market studies by Commission Staff, a conservative estimate of reduced bulk power costs during the rate cap period resulting from increased competition is about $204 million on a present value basis. The second source of customer savings is the rate cap, which results in lower rates due to the productivity adjustment. I have estimated these saving to be almost $25 million on a present value basis. This does not include the additional savings that could be achieved by the Applicants, which would be shared with ratepayers via the rate adjustment occurring at the end of the rate cap period.

Q. WHAT COSTS ARE ASSOCIATED WITH THE APPLICANTS' PROPOSALS?

A. Most of the costs of the Applicants' proposals arise from provisions associated with incentive pricing on new transmission investments. Notwithstanding the capped rate, the Applicants propose to retain the right to seek recovery of new investments that result in an increase in net plant. This additional investment will earn an incentive-adjusted return on equity of 200 basis points above the approved ROE. It is projected that new investments during the five-year rate-cap period will result in an increase in net plant amounting to about $318 million. The additional 200 basis points added to the return on equity for this portion of rate base (assuming 50% equity financed) will add about $12.9 million to rates on a present value basis.

The other area of cost from the Applicants' proposal is the initial start-up costs. However, the Applicants will not seek recovery of these costs. Given over $225 million in expected benefits, the $12.9 million in costs associated with the incentive-adjusted return on new investment is far outweighed.

II. INCENTIVE RATEMAKING

Q. WHAT IS INCENTIVE RATEMAKING?

A. Incentive ratemaking is a broad reference to the reform of traditional cost-of-service regulation in a manner that creates incentives for regulated enterprises to behave more efficiently. The basic idea is not a new one and much has been written and debated about the topic.[5] But while the topic has been well studied and understood, the application of incentive ratemaking in the electric industry has been limited.[6] Indeed, as the Commission noted in Order 2000, while its 1992 Policy Statement on Incentive Regulation[7] invited public utilities to develop and file incentive regulation proposals, none have done so.[8]

Q. DID THE COMMISSION ADDRESS INCENTIVE RATEMAKING IN ORDER 2000?

A. Yes. In Order 2000, the Commission placed considerable focus on incentive ratemaking. The formation of RTOs, to which Order 2000 is directed, is part of the primary goal of the Commission to promote efficiency and competition in wholesale electricity markets. As part of its Order, the Commission made it explicit that several ratemaking goals were desirable in the context of RTO formation. Among them were the elimination of pancaking, the management of congestion and parallel path flows, and

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5 See, generally, Incentive Regulation: A Research Report, FERC Office of Economic Policy, November 1989: Washington, D.C.

6 Basically, most experience with incentive ratemaking has been limited to fuel adjustment clauses. See *Id.*, p. 97-108.

7 *Policy Statement on Incentive Regulation*, 61 FERC ¶ 61,168 (1992).

8 Order 2000, *op. cit.* at 537-8.

the creation of incentives for efficient operation and investment in transmission systems. In fact, the Commission explicitly encouraged RTOs to propose incentive ratemaking, "particularly with respect to efficiency incentives".[9,10]

Q. WHAT TYPES OF INCENTIVE RATEMAKING DOES THE COMMISSION ENCOURAGE IN ORDER 2000?

A. The Commission encouraged two types of incentive ratemaking. The first is Performance-Based Regulation ("PBR") to promote efficient operation of existing transmission facilities. As discussed more below, one form of PBR is the use of a price cap to decouple a utility's costs from its rates. In addition, the Commission discussed performance benchmarking that links incentives to the utility's performance relative to predefined benchmarks.

The second type of incentive ratemaking in Order 2000 covers pricing policies designed to encourage efficient investment in new transmission facilities. In this regard, the Commission suggested four provisions that could be applied to new investment: higher return on equity for transmission investments, levelized capital recovery rates (i.e., fixed

9 Order 2000, *op. cit.* at 505.

10 The Applicants' commitment to join an RTO is the basis for relying on the Commission's incentives under Order 2000. The Commission was receptive to Detroit Edison's creation of the International Transmission Company based on Detroit Edison's commitment to join an RTO, even though no a particular RTO was specified (*International Transmission Company*, Docket No. ER00-3295-000 92 FERC ¶ 61,276).

amortization), accelerated depreciation, and incremental pricing for transmission investments.[11]

A. PBR: THE RATE CAP

Q. WHAT IS THE BASIS FOR THE COMMISSION'S POLICY REGARDING PBR?

A. Order 2000 explicitly encourages utilities joining or forming RTOs to propose PBR.[12] This is rooted in the well-accepted notion that PBR can affect utility incentives:

> The Commission's current interest in PBR stems from the proposition that PBR will allow the Commission to rely on market-like forces, to the maximum extent possible, to create incentives for RTOs to efficiently operate and invest in the transmission system.… [W]e believe that PBR, especially if accompanied by explicit and well-designed incentives, may provide significant benefits over traditional forms of cost-of-service regulation.[13]

Q. DO YOU AGREE WITH THE COMMISSION?

A. Yes. This position is well supported by economic theory and most economists agree that properly designed PBR mechanisms can overcome certain limitations of traditional cost-of-service regulation.

Q. PLEASE DESCRIBE THE LIMITS OF TRADITIONAL COST-OF-SERVICE REGULATION REGARDING INCENTIVES FOR EFFICIENCY.

A. Traditional cost-of-service regulation provides only limited incentives for efficient operations. Rates are based on an estimate of the cost of providing service. Hence,

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[11] Order 2000, *op. cit.* at 547-573, *NB* 565.

[12] *Id*. at 542.

[13] *Id.* at 538.

reductions in costs result in lower rates at the next ratemaking proceeding. This has the obvious impact of focusing the regulated enterprise away from intensive efforts to control costs. For example, if some up-front investment must be made to increase some aspect of efficiency, the future benefit of the investment could be reduced if the resulting cost savings are simply passed on in the form of lower rates. When the benefits are realized with some lag, there is even less of an incentive to take the risk of investing in cost-reducing technologies because the investment may be disallowed if it fails or may be appropriated in lower rates if it succeeds. Since higher costs can be passed on in rates the incentive to focus on cost reduction is muted. Not surprisingly, since efforts to reduce costs are not rewarded under cost-of-service regulation, a common charge has been that utilities do not minimize costs, particularly over the long-term.

Q. HOW CAN THESE DISINCENTIVES BE OVERCOME?

A. If costs incurred by a utility are separated from the allowed rates, then incentives can be created to undertake cost-reducing initiatives. The most common type of mechanism that achieves such a result is a rate cap. A rate cap works by placing an upper limit on the rate a utility can charge for its service. Any cost savings achieved by the utility would not result in a decrease in rates until after a significant period of time. Instead, all or a portion of the cost savings are retained by the utility, thereby creating incentives for increased efficiency.[14]

[14] A revenue cap works in a similar manner to a rate cap. Under a revenue cap, a utility is restricted in the amount of revenue that it can generate. But if cost savings are achieved, the profit margin increases, creating an incentive for more efficient operations.

Q. CAN THE CAP CHANGE OVER TIME?

A. Yes. Rate cap plans sometimes incorporate an adjustment factor to account for inflation and productivity.[15] In such a case, the cap would be adjusted at fixed intervals, usually each year, by a cost/productivity adjustment factor. In the parlance of the PBR debate, this is known as "RPI-X", from the use of this method by U.K. regulators. RPI stands for "Retail Price Index"; it is the U.K. counterpart to the U.S. CPI. "X" is a productivity offset intended to reflect anticipated productivity gains.[16] These adjustments allow the time between rate cases to be lengthened because they can reflect the inflation in costs that typically cause utilities to have to file new rates.

Q. HOW IS THE ADJUSTMENT FACTOR DETERMINED?

A. The rate cap is initially set at the cost of service rate. This generates the usual rate-case controversies. However, the methods and techniques of developing a cost-based rate are relatively well established. The adjustment factor and how it should be applied varies considerably across individual cases. In general, in order for the rate cap to change in a manner that allows a longer period of time between rate cases, an index should be chosen which tends to track costs over time.[17] For example, it might be found that the CPI has closely tracked rates over time. In addition, the index should not be

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15 A rate cap without an adjustment factor is a rate moratorium.

16 Importantly, some portion of the rate may be treated outside of the cap. For example, this might include costs that are beyond the control of the utility (e.g., taxes and capital costs in the short-term) or costs that are to be shielded from utility cost cutting efforts (e.g., demand-side management programs). As explained more below, because non-O&M costs tend to be outside the control of utility management in the short term, these costs are not subject to the rate cap.

17 See, e.g., Incentive Regulation: A Research Report, *op cit*. p. 109.

significantly affected by the utility's actions. Otherwise, the incentive effects of the rate cap may be muted.

Q. WHAT IS THE PURPOSE OF THE PRODUCTIVITY FACTOR?

A. The productivity factor is meant to adjust the cost index downward to reflect the fact that productivity may induce a smaller quantity of the inputs to which the cost index applies. For illustration, assume for simplicity that some firm has just a single input whose price increases by 10%. Assume also that the firm's productivity increases by 5% (i.e., it is able to produce 5% more with the same level of input). Under these assumptions, its total cost increases by less than the 10% indicated by the cost index. In fact, the total costs to produce the same amount (the per-unit cost) changes roughly by the difference between cost increase and the productivity increase. When both the cost index and the productivity index are known, then the true per-unit cost change is the cost index less the productivity index.

However, the RPI-X structure is not meant to precisely track the difference between the cost and productivity index. This is because some of the cost savings is to be shared between the utility and its customers. If "X" were to be set equal to the expected productivity gain, then all costs savings would be passed on to customers. In other words, the rate would exactly track the change in per-unit costs, yielding no benefit to the company. Therefore, in order to appropriately share the benefits of the expected savings, the "X" should be set lower than expected rate of productivity improvement.

For the present case, *per-unit* costs are tracked historically to exclude the cost increases that may have simply been due to increased output. Therefore, to isolate the effects of inflation on production costs alone, it is more appropriate to utilize an index comprised of per-unit costs.

Q. HOW IS THE APPLICANTS' ADJUSTMENT FACTOR DEVELOPED?

A. Because of the lack of any widely published transmission O&M cost or productivity indices, the Applicant's price cap adjustment factor is developed by comparing historical O&M costs to widely published price indices to determine an appropriate adjustment factor. If a cost index is found to closely track O&M cost increases over time, going forward one can anticipate that in the absence of PBR, costs would continue to track the index. When PBR is applied, however, the inherent incentives in the PBR structure should cause costs to rise at a slower rate. When the "X" factor is applied to reduce the index number, say an X factor of one percentage point, then the first percentage point decrease in costs is guaranteed to customers through a lower rate than that which would have occurred if the rate was based only on the inflation-adjusted costs. This benefit is guaranteed to customers, irrespective of the actual savings the company is able to achieve.

By guaranteeing the productivity gain to consumers and using an index that is not affected by the regulated firm, each dollar of reduced costs achieved by the firm would be retained under the RPI-X structure. Hence, its incentive to pursue efficiencies that would reduce its cost would be substantial, much higher than alternative systems that would share cost-reductions with consumers on the basis of actual savings achieved.

Q. PLEASE ILLUSTRATE HOW THE RATE CAP WORKS.

A. To see how the cap would work and how the sharing would result, suppose it is found that historical *per-unit* costs (which reflect inflation as well as productivity advances) track the CPI. (Indeed, as discussed below, per-unit transmission O&M costs have tracked the CPI over time.) Suppose in some period during the cap, CPI is 4%. Yet, because of efficiency incentives inherent in PBR, suppose per-unit O&M costs increase only 2%. In such a case, actual per-unit embedded O&M costs increase two percentage points slower as a result of PBR. An "X" of 1% in this hypothetical would imply that customers receive a 1% cost reduction or 50% of the 2% savings and the utility receives the other 50%. This saving mechanism provides customers with guaranteed savings because customers are ensured of the 1% savings, even if the utility does not achieve any savings.

Importantly, because the customers are guaranteed the savings through the adjustment factor, which is unrelated to the Applicants' initiatives, each dollar of savings achieved by the Applicants translates directly to its bottom line as a dollar of increased profit. Even were the Applicants' savings to amount to less than 1% so that it its costs are rising faster than the rate, the savings achieved still improve the Applicants' net profit (or loss) on a dollar-for-dollar basis. This incentive attribute is due to the fact that the consumer benefit, embodied in the X factor, is an obligation to the consumer that is completely independent of the savings actually achieved by the company. It is this attribute of the rate cap proposal that creates a strong incentive for future efficiency gains.

Q. DOES COMMISSION ORDER 2000 PROVIDE SPECIFIC GUIDANCE ON PBR?

A. No. Commission Order 2000 does not provide specific guidance on the particular PBR to employ. Instead the Commission sets forth a number of principles that should guide PBR development. Among the principles recommended in Order 2000 are those already articulated in the 1992 Policy Statement on Incentive Regulation. According to Order 2000, these are:

> (1) incentive ratemaking must be prospective; (2) participation must be voluntary; (3) incentive mechanisms must be understood by all parties; (4) benefits to consumers must be quantifiable; and (5) quality of service must be maintained.[18]

In addition to these, the Commission's RTO Order provides guidance as incentive ratemaking relates to RTOs. These are:

(a) PBR should not be piecemeal, *e.g.*, both costs and service should be addressed and all costs should be addressed, not just short term or not just long-term;

(b) PBR should encompass both rewards and penalties;

(c) PBR should induce efficiency while preserving reliability;

(d) Benefits of PBR should be shared with customers; and

(e) Rewards and penalties should be prescribed in advance.

[18] *Order 2000*, *op. cit*. at 537, fn 637, citing Policy Statement on Incentive Regulation, *op cit*. In subsequent policy orders the Commission has eliminated the requirement that benefits to customers be quantified.

In developing the Applicants' proposed rates, and as explained more specifically below, these guidelines have been used along with well-accepted PBR conventions.

1. THE RATE CAP.

Q. WILL THE ENTIRE TRANSMISSION RATE BE CAPPED?

A. Yes. The entire transmission rate will be capped at current cost of service rates. However, the cap will change in only to the extent indexed O&M costs change. In developing the Applicants' PBR proposal, the Applicants' transmission cost of service can be divided between O&M costs, A&G costs, and all other costs. A&G costs are treated separately and discussed in the testimony of Applicants' witness James Piro. O&M costs are subject to inflation over time and, therefore, can benefit from the application of an indexed adjustment.[19] Given proper incentives, these are cost areas where the activity of focused cost reduction efforts can improve efficiency. Non-O&M costs are those that are generally fixed and not subject to reduction through efforts of management. The main components of these non-O&M costs are return on equity, depreciation, and taxes.[20] The identification of the appropriate costs in each of these areas is determined in cost of service studies. Applicants' witness Mr. Piro has

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See *Statement of Policy and Request for Comments*, Docket No. RM95-6-000 and RM96-7-000 (January 31, 1996), at 46.

19 O&M costs, for the purposes of this analysis, exclude "Transmission by Others" (FERC Account 565) and excludes "Rents" (FERC Account 567). "Transmission by Others" is not considered to be a transmission-related cost at all and instead is a generation-related cost because transmission by others relates to expenses incurred to import power for on-system generation requirements. "Rents", on the other hand, are considered fixed costs, which are not something easily adjusted through managerial effort, at least in the short run.

20 For Portland General, for example, 98% of the non-O&M, non-A&G expenses were in these three cost areas.

performed such analyses. As these studies indicate, about 13% of the total cost of service constitute O&M costs.

Q. HOW WILL THE RATE CAP BE APPLIED?

A. The rate cap will change based on the test year cost of service and be adjusted each year based on the O&M cost/productivity adjustment factor, explained in the next subsection. Hence, the total rate will change in proportion to the change in O&M costs and in proportion to how O&M costs comprises the total revenue requirement. For example, since O&M costs comprise about 13% of the total cost of service, a 3% change in the O&M cost index (i.e., the escalation factor) will result in a 0.39% change in the total rate.

Q. CAN THE RATE CAP CHANGE OVER TIME IN WAYS OTHER THAN THE ADJUSTMENT FACTOR?

A. Yes. The rate cap would remain in place until the end of the rate period, which is the five-year period beginning at the effective date of these rates. After the rate cap period the Applicants could file to have the cap adjusted. As explained below, this "long-period" rate case should make only a partial adjustment toward the new cost of service so that savings achieved by the utility can be retained as a reward for increased efficiency. The absence of this particular savings provision would dull the edge of efficiency because new rates would be based on the full cost of service -- efficiencies realized in the time leading up to the subsequent rate case would be fully transferred to consumers. Allowing the Applicants to retain 50 % of the savings achieved prior to the long period rate case will retain some incentive to continue to pursue efficiency improvements.[21] Also as explained below, the Applicants reserve the right to file an intra-rate-cap-period rate case when new plant investments exceeds accumulated depreciation at any point during the rate cap period. Such a filing would only be used to seek recovery of the additional net plant created from new investments. This provision, which preserves important incentives for system expansion, is discussed more fully in the next section.

2. ADJUSTMENT FACTOR – "RPI-X".

Q. WHAT IS THE BASIS OF THE ADJUSTMENT FACTOR?

A. While certain cost savings can be achieved through utility initiatives, costs are also impacted by exogenous price increases. Hence, some allowance should be made to compensate the utility for exogenous cost increases. Likewise, a reasonable level of assumed productivity gains should be reflected in the rate cap to allow consumers to realize lower rates resulting from increased efficiency. This increased efficiency arises both from typical improvements in industry efficiency and improvements attributable to the rate cap incentives. As described above, the adjustment factor is based on the RPI-X structure.

[21] Another incentive implicit in the price cap is the incentive to increase system usage. Because rates are fixed over the rate period, to the extent usage is increased, the Applicants can earn higher profit. The increased usage attached to the system can then be used in the next rate case to produce lower rates.

Q. HOW ARE THE COMPONENTS OF THE ADJUSTMENT FACTOR SELECTED?

A. The preferred application of the RPI-X method would be to find a cost index and a productivity index for the specific costs to be tracked. In each adjustment period, some portion of the productivity index is subtracted from the cost index and the rate cap is adjusted upward by that percentage amount.[22] Unfortunately, in most applications, the best candidates for the price index and productivity factor are not intuitively obvious. In the particular case of transmission service, no adequate price nor productivity index exists for the transmission component of electric utility service, let alone the O&M portion of the service.

Consequently, the best way to determine appropriate cost and productivity indices is to analyze how actual costs have tracked the various cost indices that are available. Therefore, I have created a per-unit O&M cost index based on the historical O&M cost per-unit of monthly peak demand of all U.S. utilities and compared it to the CPI, the Producer Price Index ("PPI"), and the Gross Domestic Product Price deflator ("GDP Deflator"). These three cost indices are the most widely used and understood indices.

Q. WHAT ARE THE DIFFERENCES BETWEEN THESE THREE MAJOR COST INDICES?

A. The three major cost indices measure different aspects of costs. The CPI is by far the most familiar and easily understood. It measures the change in prices of typical goods purchased by retail customers. It is the most widely used index for tracking changes in

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[22] Only a portion of the productivity index is subtracted from the cost index so that some of the cost savings from the productivity gain can be retained by the utility as an incentive to reduce costs.

the overall price level in the economy. The PPI is an indicator of input costs faced by producers. It measures prices paid at the wholesale level for goods used by producers as inputs for the production of final goods. The PPI is tracked at different levels of production varying from crude inputs to finished wholesale goods. The GDP deflator tracks both final consumer goods and goods purchased by businesses and government. It is therefore a broader index of prices than the CPI or the PPI.

One important factor in choosing the most appropriate index is how well the index has been historically correlated to the relevant costs that will subject to the indexed adjustments, O&M costs in this case. Accordingly, I choose an index based on how historical O&M costs have tracked each of the three major indices.[23]

Q. HOW HAVE YOU MEASURED THE HISTORICAL TREND IN O&M COSTS?

A. I measured historical per-unit O&M costs by creating an O&M index on a per-MW of monthly load basis that can be compared to the major price indices. This O&M cost index was created by aggregating the total O&M costs for all investor-owned utilities and dividing by the sum of the 12 month peak loads. The data are for the six years 1995 through 2000, as reported by the utilities on FERC Form 1. As Exhibit TC-6 shows, for all investor-owned utilities, unit O&M costs have increased by over 20% between 1995 and 2000. This represents a compound annual growth rate of about 4%.

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[23] One might be inclined to propose the O&M index itself as an escalation factor since this index uses actual O&M costs from U.S. utilities. A serious drawback to such an approach is the lag which is attendant in the data that would be necessary for constructing such an index. The O&M data are reported in the FERC Form 1 which is public only many months after the end of the year in which the costs were incurred. Common cost indices, on the other hand, are available less than one month after year's end. Also, the O&M index requires significant data and data processing, something that can add further delay to an index calculation.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE AGGREGATE DATA?

A. Yes. While the cost experience of all utilities during that time period provides a good indication of cost trends, some adjustments to the data were undertaken to correct for potential cost changes *unrelated* to general price increases. In particular, unit O&M cost data for some utilities show anomalous changes in some years. These anomalies can be caused by many different factors, including refunctionalizing of costs, changes in load classifications, or data errors. Including these factors can distort the historical cost index. Therefore it is reasonable to adjust the index to eliminate some of the outlying observations in order to ascertain the trend experience by the most typical utilities.

Q. HOW DID YOU ADJUST THE DATA TO ACCOUNT FOR THESE ANOMALIES?

A. In order to eliminate anomalous data from the analysis of the historical trends in O&M costs, I created a second index that does not include utilities whose increases or decreases in unit costs were particularly large. Specifically, I examined the O&M costs of only those utilities whose costs change were in the middle 80th percentile of all utilities. To do this, I sorted utilities in ascending order of unit cost increases, then eliminated the highest 10% and lowest 10%. As shown in Exhibit TC-7, this reduces the trend in cost increases to an average rate of about 3.7%. An analogous index including only utilities within the WSCC produces similar results, showing an annual growth rate of 3.2%.

Q. HOW DOES YOUR O&M INDEX COMPARE TO THE MAJOR COST INDICES?

A. Exhibit TC-7 shows a comparison of unit O&M costs to the CPI, the PPI, and the GDP deflator. The comparison shows that the CPI most closely tracks the historical data, supporting the conclusion that the CPI provides the most appropriate basis for prospective cost adjustment. While the CPI tracks the O&M index more closely than the PPI or the GDP Deflator, the CPI actually increased at a substantially slower rate than O&M costs over the period. CPI grew at an annual rate during the period of 2.5 % – roughly 1.2 % lower on an annual basis than the O&M index.

Q. HAVING RECOMMENDED THAT THE CPI BE USED FOR THE PRICE INDEX COMPONENT OF THE RATE CAP FORMULA, WHAT DO YOU RECOMMEND FOR THE PRODUCTIVITY FACTOR?

A. As discussed above, the use of a per-unit O&M cost index implies that the productivity adjustment is already reflected in the index. This is because the per-unit index accounts for both changes in the price of the input as well as changes in the amount of the input used. If an input is used less intensively to produce the same output, this reflects a productivity increase, and per-unit costs will decrease even if the input price stays the same. Therefore, the per-unit cost index incorporates both price changes and productivity changes. As a result, if the price cap were to change in exact accordance with the per-unit cost index, then the cap would exactly equal the cost of service. Therefore, such an index would provide all savings to customers and there would be no need for an “X” to reduce the rate cap further. In fact, an “X” would need to be added to the index to allow the utility to retain some savings and thus establish the desired incentives.

However, the CPI tracks historical per-unit costs and these costs have not been incurred pursuant to incentive rates. This implies that, going forward, per-unit costs should grow more slowly that they have historically, at least for utilities like the Applicants that are under PBR. Therefore, only a relatively small productivity factor is appropriate -- I am recommending a 0.5% factor. The total annual adjustment index would be CPI - 0.5%. This will guarantee that O&M portion of the customers' rates change more slowly than general inflation, even though the empirical evidence shows that these costs increase faster than general inflation and even though the index is based on per-unit costs which include productivity improvements.

Exhibit TC-8 shows the effect of a 0.5% annual reduction on the CPI index. The cumulative effect of this reduction becomes relatively large over time and produces a trend that is well below the historical growth in utilities' transmission O&M costs.

3. LONG-PERIOD RATE CASE.

Q. HOW SHOULD THE RATE CAP BE ADJUSTED?

A. As part of the rate cap plan, even though a rate case is supposed to be delayed for a substantial period of time in order to make the rate cap incentives effective, there will still be the need for a what might be termed a *long-period rate case*. This long-period rate case is necessary to make periodic adjustments to the caps after allowing the cap to remain in place long enough to affect the desired efficiency improvements. The purpose of this rate case is to re-establish the cost-basis for the rate. In doing so, however, all of the savings will normally be transferred to the customers. Something that would substantially mitigate the incentive for the company to reduce costs as the rate case approaches.

Q. WHAT PROVISIONS WOULD YOU RECOMMEND TO MAINTAIN THE INCENTIVE TO REDUCE COSTS?

A. The mechanism for adjusting the cap can be designed in a way that retains incentives to increase efficiency. If the rate cap is adjusted at the long-period rate case at the new cost of service, then the incentive to reduce costs as the new rate case approaches is undercut. The incentive is reduced because higher costs in the periods before the cap adjustment will result in a higher cap, to the benefit of the utility seeking higher rates. To avoid this, the O&M portion of the rate should be set at the average of the actual cost at the time of the long-period rate proceeding and the prevailing cap. This allows the transmission utility to keep 50% of the savings that it had affected since the time of the cap. For example, if the O&M portion of the cap is $2 per MW and the actual O&M cost of service at the time of the next rate case is $1.50, then the O&M rate would be set at $1.75. Similarly, if the utility had failed to achieve the assumed productivity gains, for example the O&M portion of rates increase from $2 to $2.50, then the rate would be set at $2.25 and utility would incur 50% of the higher costs in rates going forward. This provision would provide an important incentive for the Applicants to continue to aggressively pursue cost-saving efficiencies toward the end of the period preceding the long-period rate case. In addition, the provision provides for an equitable sharing of the savings achieved during the rate cap period.

B. TREATMENT OF A&G EXPENSES

Q. HOW WILL THE APPLICANTS SHARE SAVINGS ASSOCIATED WITH A&G EXPENSES?

A. As described in the testimony of the Applicants' witness James Piro, the Applicants propose to share A&G savings through an annual "true-up" mechanism whereby one-half of the reduction in A&G expenses as compared to the test year will be returned to customers in the form of reduced tariffed rates.

Q. IS THIS TREATMENT OF A&G EXPENSES APPROPRIATE?

A. Yes. It is appropriate for the Applicants to retain a portion of the savings as an incentive to undertake TransConnect formation. As described above, the formation of independent transmission companies ("ITCs") is consistent with the Commission's policy objectives as outlined in Order 2000 and subsequent orders. Therefore, allowing these companies to retain a portion of the savings related to their formation will serve as an important incentive to form ITCs. The response of the Commission in this case is particularly important due to the signal it will send to the other transmission owners that may be considering forming an ITC. I also note that the proposal to allow A&G cost savings to be shared with rate payers creates an added incentive for TransConnect to reduce costs. This is because every dollar saved in A&G costs will result in an increase of one-half dollar in additional income.

C. PBR: BENCHMARKING

Q. WHAT IS BENCHMARKING?

A. Benchmarking is the use of performance measures (benchmarks), presumably focused on the operation of the system or quality of service, to provide a specific set of incentives for the firm. They are useful in the context of incentive rates as a means to augment the incentives in areas where the firm might otherwise lack efficient incentives. Price caps, like the one proposed above, for example, have been criticized for providing an incentive for a firm to cut costs by allowing service quality or reliability to decrease. Benchmarking addresses this criticism by providing incentives linked to service quality and reliability benchmarks. Designing appropriate benchmarks and establishing efficient incentives and penalty levels are very important to ensure that the benchmarking proposal will not distort the behavior of the transmission owner or operator by providing incentives that are either too strong or too weak relative to the price cap incentives.

Q. HAVE THE APPLICANTS PROPOSED SPECIFIC PERFORMANCE BENCHMARKS?

A. Not yet. While the Applicants support benchmarking, they agree with the Commission's policy in Order 2000 that these benchmarks should be developed in a collaborative process among all stakeholders and introduced when the collaborative process has been completed. The process to implement benchmarking incentives would be initiated by the Applicants. After sufficient experience has been achieved under actual operation within TransConnect, the Applicants will propose candidate benchmarks together with the preliminary estimates of the benchmarks during initial operations. Utilizing actual operating data will allow the Applicants to develop an appropriate set of benchmarks and incentives and will facilitate input by the stakeholders. The Applicants will work closely with stakeholders to develop and refine the benchmarks and associated incentives and penalties. This stakeholder process should include gathering written input as well as hosting a series of stakeholder meetings to discuss the benchmarking alternatives and to receive comments. Following this stakeholder process, the Applicants would make the decision whether to propose the benchmarking provisions to the Commission.

D. INCENTIVE RATEMAKING FOR NEW INVESTMENTS

Q. HOW CAN INNOVATIVE RATEMAKING PROVIDE EFFICIENT INCENTIVES ON A LONG-TERM BASIS?

A. The primary intent of the rate cap described above is to improve the efficient operation of existing facilities. Over the long-term, however, the value of the system in aiding a well-functioning bulk-power market will be heavily dependent on the efficient expansion of the transmission network. The Commission recognized this in Order 2000 by suggesting that rate treatment for new transmission investment be addressed as a separate matter from PBR.[24]

In accordance with the Commission's guidance, I propose a number of innovative ratemaking mechanisms to address new investment requirements for the Applicants.

The motivation is to create incentives to make necessary and efficient investments for maintaining and expanding transmission network capabilities.

Q. WHAT PROVISIONS DO YOU PROPOSE FOR NEW INVESTMENTS?

A. I propose two compensation mechanisms for new investments. First, certain investments that provide system-wide benefits and cannot be directly assigned to a specific users will be recovered on an embedded-cost basis through system-wide zonal rates. Second, investments made in response to a transmission service request, a generator interconnect request, or by the Applicants themselves will be directly assigned to the responsible party. In exchange, the party will receive any firm transmission rights or service facilitated by the new investment.

Q. HOW DO YOU ENVISION THE APPLICANTS WORKING WITHIN AN RTO STRUCTURE IN THE TRANSMISSION PLANNING PROCESS TO FACILITATE THESE INCENTIVE PROPOSALS?

A. In their role in the transmission planning and expansion process, RTOs may require certain investments to maintain system reliability. With regard to other investments, the Applicants and all other transmission investors would be required to coordinate with an RTO in planning the investments to ensure that they do not conflict with RTO planning objectives (i.e., do not impair reliability or total transfer capability).

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[24] Order 2000, *op. cit.* at 570.

Q. WHAT OTHER RESPONSIBILITIES WOULD YOU PROPOSE FOR THE RTO - RELATED TRANSMISSION EXPANSION?

A. As the administrator of the Firm Transmission Rights that will be key in managing congestion, the RTO should be responsible for quantifying the additional capability resulting from the new investments. This quantification is needed to allow the investor to receive the Firm Transmission Rights associated with the investment, which is critical in its market value.

1. NEW INVESTMENTS AT EMBEDDED COST RATES.

Q. WHAT TYPES OF NEW INVESTMENTS WOULD WARRANT EMBEDDED COST TREATMENT?

A. There are two types of investments that could be requested of the Applicants that cannot be directly assigned and which should be placed into the Applicants' ratebase and recovered at embedded cost rates. First, an RTO may require certain upgrades and expansions from time to time to conform to RTO planning criteria. The second type of investment costs that may not be directly assignable are those costs that transmission customers or the Applicants successfully show provide system-wide benefits. Hence, capability-enhancing projects that reduce congestion and provide for the creation of new Firm Transmission Rights (a process discussed more fully below) could also provide reliability or other benefits that warrant the allocation of a portion of the investment costs to all customers.

The capital costs qualifying for embedded cost treatment will be rolled into ratebase and recovered through system-wide zonal rates. However, under the rate cap proposal discussed above, no provision is made for an increase in rates when such new costs are incurred during the rate cap period. Under certain circumstances, this can cause significant incentive problems. These problems arise if new investment is added faster than the existing facilities are being depreciated, causing an increase in net transmission plant. A capped rate anticipates a somewhat constant amount of net transmission plant, as the cap reflects capital cost associated with unrecovered investment as of the time the cap is put into effect. If net plant increases over the rate cap period, the utility is prevented from realizing any return on the new investment during that time frame. This would create a significant disincentive to incur these types of new investment costs. To remove this disincentive and maintain the rate cap, the Applicants propose to retain the right to file during the rate cap period for recovery of capital costs to the extent the capped rate is insufficient.

By retaining the right to file an incremental rate to reflect the additional capital costs associated with the increase in net plant, the Applicants would thereby retain the incentive to expand the system.

Q. SHOULD THESE INVESTMENTS BE TREATED DIFFERENTLY THAN EXISTING INVESTMENTS?

A. Yes. The return on equity on these new investments should be higher than the return on existing plant to ensure that the Applicants will have an adequate incentive to commit significant capital to new investments. Therefore, the Applicants are proposing a 200-basis point incentive premium over the return on equity approved for existing plant along with an accelerated depreciation schedule.

Q. WHAT IS THE BASIS FOR THE INCENTIVE-ADJUSTED RATE OF RETURN?

A. The incentive-adjustment to the return on equity is a mechanism to ensure the Applicants will have adequate incentives to undertake new investment projects and attract the necessary capital in light of new risks facing the industry and independent transmission companies in particular. The Commission has correctly raised significant concerns regarding under-investment in the transmission system, especially in the West.[25] This provision, together with the 15-year depreciation provision would provide a reasonable means of addressing these concerns.

2. MARKET-MOTIVATED NEW INVESTMENTS.

Q. EXPLAIN THE APPLICANTS' PROPOSAL TO MAKE MARKET-MOTIVATED INVESTMENTS.

A. The embedded cost rate mechanism described above ensures that the system will be expanded in response to reliability needs, as defined through the RTO planning process, or other system-wide considerations. In addition to expanding transmission for those purposes, allowing transmission customers, merchant transmission investors, and the Applicants themselves to make discretionary investments in transmission facilities is a critical component of the transmission expansion framework. These investments should be made in response to the economic signals provided by the market to alleviate congestion. In fact, these investments will be responding to the same market signals as

[25] *Further Order on Removing Obstacles to Increased Energy Supply and Reduced Demand in the Western United States and Dismissing Petition for Rehearing,* 95 FERC ¶61,225 (2001).

investments in new generation and, therefore, should therefore be designed to compete fairly and efficiently with new generation projects.

Q. HOW WILL INVESTORS BE COMPENSATED FOR THESE INVESTMENTS?

A. When a transmission customer or other investor makes an investment, the Firm Transmission Rights associated with this capability would be allocated to the investor. These rights may be used or sold to others at market rates. This provision provides an appropriate market-based incentive to relieve congestion when the value of relieving congestion exceeds the cost of expanding the transmission capability. It also creates a competitive alternative to new generation (or existing high-cost generation).

Q. WILL THIS SYSTEM PROVIDE EFFICIENT INCENTIVES TO BUILD NEW TRANSMISSION?

A. Yes. As long as the investor is granted the rights to the incremental capability that its investment creates, the value of the rights granted to the investor should approximate the market benefit of adding the capability. Therefore, investments that are more costly than the benefits created will not be undertaken while investments that create large net benefits will be sought out and implemented.

Q. IS THIS ALWAYS THE CASE?

A. No. Some types of transmission investments are lumpy, requiring relatively large investments that eliminate more congestion than would be economic if smaller investments were possible. In these cases, the investments may reduce the value of the transmission rights to the point that the rights will not adequately compensate the investor even though the investment is efficiency-enhancing. In these cases, allowing the investor to propose that some or all of the investment costs be included in rate base and recovered through embedded cost rates is appropriate. However, such proposals should be contingent on a showing that the benefits of the project exceed its costs.

Q. HOW CAN ALLOWING DISCRETIONARY INVESTMENTS INCREASE COMPETITION IN GENERATION MARKETS?

A. As the capability of the system is expanded through facility upgrades, customers in congested areas of the system will have access to additional generation that would previously have been precluded by the congestion. This will lead to broader geographic markets with increased competition among generators. Eliminating localized market power due to congestion by building new transmission capacity is extremely important in the emerging power markets because other means of mitigating this form of market power have not yet proven to be reliable.

Q. THE COMMISSION'S ORDER IN THIS CASE EXPRESSED CONCERN THAT THE APPLICANTS' AUTHORITY TO MAKE DISCRETIONARY INVESTMENTS MIGHT FAVOR TRANSMISSION FACILITIES OVER NON-WIRES SOLUTIONS. WHAT IS YOUR OPINION?

A. The Commission's concern is that power generation and/or conservation measures may not be developed because transmission solutions will be favored by the transmission company. For example, a transmission line may be built that allows distant generation resources to be transferred to load centers instead of local generation being built or instead of conservation measures being taken. While it is true the Applicants would have the incentive to build transmission to relieve power supply constraints, the Applicants would have no authority to deny the installation of new generation or new demand-side measures. Generation interconnection is regulated by the Commission and would be facilitated by the RTO.

To the extent these new power supply options require new transmission capacity, the Applicants would be required under Commission policy to undertake upgrades and expansions to accommodate interconnection requests. In this context, the transmission upgrades are complements to the generation investments.

In other cases, transmission upgrades to reduce congestion may compete with new sources of supply (or decrements of demand). In this context, it is beneficial to allow transmission remedies to place competitive pressure on generation investments to the extent that the transmission remedies are more economic. If they are not more economic, the generation investments will proceed. The only real concern is whether generation investments will have an inefficient competitive advantage over transmission investments since large transmission projects generally take longer to site and construct than generation. Unfortunately, these issues cannot be resolved unilaterally by the Applicants, but require attention from the States and the Commission and should be considered in the planning process.

3. NEGOTIATED RATE AUTHORITY.

Q. SHOULD THE APPLICANTS BE PERMITTED TO NEGOTIATE ALTERNATIVE RATE STRUCTURES WITH TRANSMISSION CUSTOMERS?

A. Yes. In order to more efficiently operate the transmission system and to respond to the changing wholesale market requirements, the Applicants should be allowed to negotiate alternative rate structures. This negotiating authority is modeled after the Commission's negotiated/recourse rate authority granted to natural gas pipelines.[26] Under the negotiated/recourse rate structure, the Applicants would be permitted to offer discounts and other alternative rate structures provided customers have recourse to the tariff rate structure and provided that the service is non-discriminatory. The main motivation for alternative rate structures is to more fully utilize the transmission system and to achieve more efficient use of it.

Q. HOW CAN ALTERNATIVE RATE STRUCTURES INCREASE SYSTEM USAGE?

A. Certain rate structures may be more economic for some customers than for others, given the differences in how customers intend to utilize their transmission reservations. While simple discounts from the tariff rate can facilitate efficient transactions that more fully utilize the transmission system, alternative rate structures may be a superior means to accommodate the particular requirements of a transmission customer. For example, a customer with an extremely low load factor may forgo taking transmission service

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26 *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines* and *Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶61,076 (1996).

priced on a peak-load basis, but may be willing to negotiate an alternative rate on a volumetric basis. Negotiated arrangements may also be beneficial in cases where the customer requires a specific type of service (e.g., off-peak service or service in directions that are counter to the prevailing system flows). Having the flexibility to offer these types of alternative arrangements to individual customers should allow the Applicants to better meet the needs of customers and improve overall system utilization.

Q. WILL CUSTOMERS WHO NEGOTIATE AN ALTERNATIVE RATE STILL HAVE ACCESS TO THE FULL RATE?

A. Yes. Customers that are offered negotiated rate alternatives will have recourse to the filed tariff rate. This protects customers from being compelled to accept a negotiated rate alternative that is inferior or more costly to them than the filed rate. However, to avoid gaming, once a customer goes back to the recourse rate, the Applicants would not be obligated to offer that customer the negotiated rate.

Q. TO WHAT EXTENT WILL NEGOTIATED RATES BE AVAILABLE TO ALL CUSTOMERS?

A. The Applicants will implement their negotiated rate authority on a non-discriminatory basis. Thus, customers that are similarly situated to customers receiving negotiated rates will be entitled to receive the same rates under Commission policy. However, customers not similarly situated will not necessarily be entitled to receive the same rate.

Q. IN LIGHT OF THE APPLICANTS' ABILITY TO INDIVIDUALLY NEGOTIATE WITH CUSTOMERS, IS DISCRIMINATION A CONCERN?

A. No. Since the Applicants will be part of an independent transmission company, they would not have the incentive to discriminate in favor of any one transmission customer. The Applicants' objective would not be the success of one market participant over another, but rather to maximize system utilization. Also, these negotiated rates will be filed at the Commission and rates filed at the Commission are subject to public inspection.

III. ANALYSIS OF BENEFITS AND COSTS

Q. WHAT IS YOUR ANALYSIS OF BENEFITS AND COSTS?

A. My analysis of benefits and costs weighs the anticipated beneficial aspects of the Applicants' proposal against its costs. The benefits from the Applicants' proposal are two-fold. First, the most important benefits arise from increased competitiveness in wholesale (and ultimately) retail power markets. Second, benefits also accrue through customer savings under the rate cap and the sharing of A&G cost savings. The costs of implementing the ratemaking reforms are incurred by customers as the result of the incentive-adjusted ROE on new plant investment and the fixed start-up costs of the Applicants.

A. BENEFITS FROM INCREASED COMPETITION

Q. WHAT ARE THE COMPETITIVE BENEFITS OF THE APPLICANTS' PROPOSAL?

A. The single most important advantage of the Applicants' proposal in conjunction with RTO formation is the broadening of the wholesale marketplace. Indeed, this is the main motivation for instituting Order 2000 reforms. As stated by the Commission:

> [RTOs] could improve efficiencies in grid management through improved pricing, congestion management, more accurate estimates of Available Transmission Capability, improved parallel path flow management, more efficient planning, and increased coordination between regulatory agencies. Appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation.[27]

Q. EXPLAIN HOW THESE BENEFITS WILL BE ACHIEVED?

A. First, RTO formation will improve the coordination of transmission operations in the region. Under prevailing arrangements, transmission flows are managed by individual transmission owners. Because the flows on each owner's system are heavily dependent on the transactions scheduled and the generators dispatched on other systems, congestion is generally managed using physical curtailment of transactions. This method of managing transmission congestion is widely acknowledged as inefficient and likely to lead to under-utilization of the transmission system.

Once the RTO is operating, the flows on the system will be better coordinated since the RTO will encompass most of the parallel paths over which power flows. Moreover,

[27] *Order 2000*, *op. cit.* at p. 3, (footnote omitted).

once an RTO implements a congestion management system, economic signals will replace the physical curtailment regime to efficiently resolve transmission constraints. Proper economic signals provide correct incentives for generators to alter their output or transaction quantities to maximize the utilization of the transmission network while maintaining the flows over all transmission facilities within their physical constraints.

Q. WILL THE RTO BE BETTER ABLE TO COORDINATE RESERVATIONS?

A. Yes. The RTO will have the ability to better coordinate the estimation and reservation of transmission capability, which is currently done by each of the individual transmission owners with limited coordination. This will increase the value of the transmission reservations to customers in two ways. First, the coordination will likely allow the RTO to make additional capability available in total. Second, by coordinating the capability available on alternative transmission paths, the RTO will be able to maximize the amount of capability available on the most valuable paths. In both cases, customers seeking the transmission reservations will directly benefit from the improved coordination.

Q. DOES THE APPLICANTS' PROPOSAL ADVANCE THE COMMISSION'S RTO GOALS?

A. Yes. Aside from the generally recognized economic benefits of RTO formation, which progress as a result of Applicants' proposals, TransConnect is also set up in a manner to allow members to fully divest their transmission assets into a stand-alone transmission enterprise. This further extends the Commission's transmission objectives by separating the monopoly delivery function from bulk-power market participants, focusing TransConnect's management on a single segment of the utility power supply chain (resulting in innovative and expanded service), and increasing market efficiency due to efficient market-based decisions with respect to expansion and upgrades.

Q. HOW IS THE SEPARATION OF GENERATION FROM TRANSMISSION AN ADVANTAGE ARISING FROM A STAND-ALONE TRANSMISSION BUSINESS?

A. The Commission's goal in Order 2000 is the promotion of bulk-power market competition through RTO formation. The elimination of pancaked transmission charges and the transfer of operating control away from generation-owning entities are the two main ways RTO formation can do this. The Applicants' proposal advances this goal by making further separation through formation of a stand-alone entity. The elimination of discriminatory transmission rates and service has been an appropriate long-standing goal of Commission policy. The corporate separation of the transmission business by the Applicants goes further in advancing this goal than the Commission has required.

Q. HOW IS AN INCREASED FOCUS ON TRANSMISSION AN ADVANTAGE FROM A STAND-ALONE TRANSMISSION BUSINESS?

A. The TransConnect proposal provides the ability of management to focus on a single line of business as opposed to the integrated operation of generation, transmission, and distribution. This will likely result in innovative transmission and transmission-related products and features that will benefit customers. Instead of being only one element in the supply chain of a vertically-integrated utility, a for-profit transmission company will have a singular focus and be more active in seeking ways to facilitate power trading in order to increase system utilization. The telecommunications industry serves as a good example of the innovative products that can develop as regulatory policy seeks to rely on market forces. Allowing for-profit control of the transmission system promises to unleash the analogous incentives and benefits.

Q. HOW IS MARKET EFFICIENCY AN ADVANTAGE FROM A STAND-ALONE TRANSMISSION BUSINESS?

A. A third major advantage of the stand-alone transmission business is the capacity to allow innovative ratemaking that can encourage efficient investment going forward. If the ownership interest between a generation owner and the transmission system owner is retained, giving the transmission owner authority to plan and invest in the system in a discretionary manner requires additional administrative safeguards to stem potential anticompetitive discrimination. But by eliminating or severely restricting ownership control by market participants, as in the Applicants' proposal, efficient incentives can be devised, such as the ones being proposed by the Applicants.

Q. HAS THE COMMISSION RECOGNIZED THE BENEFITS OF A STAND-ALONE TRANSMISSION COMPANY?

A. Yes. The Commission has recognized how establishing an independent transmission company can achieve these important benefits. In a recent Order approving innovative rates for the International Transmission Company, an independent transmission company formed by Detroit Edison, the Commission emphasized the value of creating a stand-alone transmission company:

> …[W]e agree that a stand-alone transmission business, unaffiliated with any market participant, holds the potential to attract the necessary capital to accelerate the benefits of the Commission's open access and RTO initiatives.[28]

Q. ARE THE APPLICANTS POISED TO ACHIEVE THESE BENEFITS?

A. Yes. The Applicants have proposed the independent transmission company for the very reason of creating an independent entity that has no interest in the success of any particular market-place participant over any other one. In considering the benefits of the Applicants' incentive regulation proposals, the effect of the stand-alone transmission business and its impact on improved market performance is a major benefit.

The innovative rate provisions also provide competitive benefits by allowing the Applicants to make discretionary transmission investments and then market the capability created by the investments. Not only does this create a market test for transmission investments (i.e., the economic benefits of relieving congestion through expansion or upgrades must exceed the investment cost), it also creates competition in generation markets. This increased competition will place downward pressure on price and result in the corresponding economic benefits associated with lower prices. Combined with the elimination of pancaking and the elimination of incentives for discrimination, these provisions will contribute to more vibrancy in electric power markets. While a precise estimate of the savings associated with these pro-competitive

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28 *International Transmission Company*, *op cit*.

measures would be complex, even the slightest enhancement of market performance results in substantial benefits.

Q. HAVE YOU QUANTIFIED THE COMPETITIVE BENEFITS?

A. Not directly. The underlying benefits of the Applicants' proposal are rooted in the enhancement of competition in regional power markets through successful RTO formation. But, as discussed above, the Applicants' proposal to form TransConnect stands to produce competitive benefits in its own right as a result of its corporate separation from market participants.

The quantification of competitive benefits is difficult and would require a complex and detailed study. Instead of conducting such a study, I have relied on results of the Environmental Assessment by Commission Staff in Order 2000. According to this study, RTO formation can result in annual cost reductions of between 1.1% and 2.4 % of total electric power costs.[29] Given the competitive and efficiency benefits discussed above, this range of estimated benefits is very reasonable.

Even the low end of this estimate results in a substantial benefit. Total electric operating costs (i.e., generation, transmission, and distribution expenses as reported on FERC Form 1) for the Applicants totaled about $4.2 billion in 2000. If 1.1% of these costs are realized as savings as a result of RTO and TransConnect formation, benefits could reach about $46 million annually. On a discounted basis (discounting at 6%), $46 million over each of the years 2002-2006 has a present value equal to about $204 million.

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[29] *Order 2000*, *op. cit.* at p. 95.

B. BENEFITS FROM THE RATE CAP

Q. HOW DOES THE RATE CAP PROVIDE BENEFITS TO RATEPAYERS?

A. The rate cap plan provides benefits from cost savings associated with the efficiency incentives. The rate cap plan allows customers to retain at least 0.5% savings in transmission O&M costs that otherwise would have been reflected in rates due to inflation. This is because the O&M portion of rates increases (at most) by at 0.5% less than inflation. Because O&M costs, absent the incentive plan, would increase at least by the rate of inflation, as shown above, the cap growing slower than inflation is a rate benefit to customers. Indeed, the savings will be even higher than this because, as discussed above, O&M costs have historically grown at rates higher than inflation by an average of 1.2 percentage points per year. Hence, with the O&M portion of rates under the rate cap growing at 0.5% slower than inflation, the O&M portion of rates will increase 1.7 percentage points slower than the if they had grown at their historical rates.

Q. PLEASE PROVIDE AN ESTIMATE OF THESE SAVINGS?

A. Total O&M expenses for the Applicants are about $21.8 million. Therefore, customers would realize total savings of 1.7% of the total O&M expenses compounded each year assuming that O&M costs would otherwise have maintained the same relationship to CPI. Table 1 shows how the savings accrue over the five years of the rate cap period.

Table 1
Illustration of Savings Associated with Rate Cap

	Year					
	2002	2003	2004	2005	2006	Perpetuity
O&M without Cap (Annual Increase of 3.7%)	$100.00	$103.70	$107.54	$111.52	$115.64	
O&M under CPI-.05 (Annual Increase of 2%)	$100.00	$102.00	$104.04	$106.12	$108.24	
Cumulative Savings		$1.70	$3.50	$5.39	$7.40	
Percentage Savings		1.7%	3.5%	5.4%	7.4%	
Actual Test Year O&M Expenses	$21,800,000					
Projected Actual Savings		$370,600	$762,324	$1,176,102	$1,612,902	$28,494,600
Present Value		$349,623	$678,466	$987,478	$1,277,569	$21,292,823
Present Value through 2006	$3,293,136					
Total Present Value	$24,585,959					

The first row of Table 1 illustrates how a $100 O&M component of rates in 2001 would increase if it followed the historical 3.7% increase that O&M costs have followed. By 2006, the $100 grows to $115.6. Using historical inflation of 2.5% and reducing this rate by 0.5% (to 2.0%), the second row of Table 1 shows how O&M costs are projected to change under the rate cap plan. By 2006, the capped rate is a full $7.4 dollars lower than uncapped rate.

Because in the example in the Table the base O&M expense was $100, the cumulative savings translate to percentage savings. Hence, in 2003, rates would have been 1.7% higher than had the rates reflected the historical increases in O&M expenses. Likewise, rates would have been an *additional* 1.7 % higher in 2004. Compounded with the 1.7% savings in 2003, the total savings at the end of 2004 would be approximately 3.5%. Similarly, savings increases each year would compound to approximately 7.4% by 2006. Given the $21.8 million in Applicants' O&M costs, Table 1 also shows the present value of the total savings over the five year period is $3.3 million. However, this is an extremely conservative estimate of savings because other savings likely would be generated by the rate cap.

Q. WHAT OTHER SAVINGS LIKELY WOULD BE GENERATED BY THE RATE CAP?

A. In addition to the direct savings computed above, the incentives provided by the rate cap are likely to result in additional costs reductions or other savings achieved by the Applicants. These savings would be shared with ratepayers at the time of the next rate case after the rate cap period ends. I have not attempted to forecast these cost reductions. However, even under the extremely conservative assumption that the Applicants achieve no more cost reductions after 2006, the $1.6 million in 2006 savings would enjoyed in perpetuity each subsequent year. The present value of $1.6 million in perpetuity after 2006 is $21.3 million. Hence, the total rate benefit to customers on a present value basis would be $24.6 million (=$3.3 million + $21.3 million).[30] Of course, it is highly unlikely that the Applicants would not continue to realize cost reductions as long as sufficient incentives remain under the rate cap. Therefore, the benefit is likely to be considerably larger than this estimate.

30 I note that this calculation is based on the assumption that the Applicants could collect all of their cost increases in periodic cost of service filings. Because of regulatory lag, some cost increases from year-to-year would not be reflected in rates immediately.

Q. WILL CUSTOMERS BENEFIT FROM THE APPLICANTS' PROPOSED TREATMENT OF A&G EXPENSES?

A. Yes. As discussed in the testimony of Applicants' witness Jim Piro, customers will receive one-half of the savings of A&G expenses as compared to the test year amount in each of the 5 years of the rate plan. While savings cannot be accurately measured at this time, they are expected to be significant.

C. ESTIMATED RATEPAYER COSTS

Q. WHAT ARE THE SOURCES OF THE COSTS OF THE APPLICANTS' PROPOSAL?

A. There are two areas of costs. First, there are the costs of starting-up TransConnect, including legal fees and consulting costs, renovation and construction of necessary facilities, new equipment, and training personnel. The Applicants have indicated that they will not seek recovery of these costs from customers. Hence, the only area of costs is the second area of costs, which emerge from the application of the incentive-adjusted return on equity on new investments. As discussed above, in order to retain important investment incentives, the Applicants propose to retain the right to file for higher rates to recover incremental net plant costs during the rate cap period. And these new investments would earn a 200-basis-point incentive-adjusted ROE.

To estimate the additional cost-of-service that this incentive adjustment will require, I have used the Applicants' projected new investments for the rate cap period to determine how the 200-basis-point incentive adjustment would increase transmission cost-of-service.

Exhibit TC-9 illustrates the cost of the 200-basis-point incentive-adjusted return on unrecovered new plant investment. The projected embedded cost investments were provided by the individual Applicants. Projected net plant investment is shown in Column (1). The increase in net plant from year to year, shown in Column (2), represents the amount of cost incurred in each year in excess of depreciation. This represents new plant eligible for incremental rate treatment in accordance with the proposals outlined above. The cumulative change in net plant, shown in Column (3), represents the unrecovered new investment at the end of each year. Assuming 50% equity financing, one-half of the amount of cumulative net plant would be subject to the 200-basis-point incentive return. Hence, the Column (4) of Exhibit TC-9 shows the amount of additional equity costs in each from the 200-basis-point adjustment. The present value is shown in Column (5) of the Exhibit and totals about $12.9 million. This analysis assumes the Applicants indeed seek recovery during the rate cap period. To the extent recovery is not requested, the costs will be smaller.

Q. PLEASE SUMMARIZE YOUR COST/BENEFIT ANALYSIS.

A. The Applicants' proposal promises to result in over $250 million in benefits -- $204 million from more efficient market operation and about $25 from the rate cap. This is far in excess of the $12.9 million in costs associated with incentive-adjusted ROE. And although the over $200 million in savings from more efficient markets are also attributable to RTO formation the benefits from the rate cap alone ($25 million) outpace the costs from the incentive-adjusted ROE.

IV. CONSISTENCY WITH COMMISSION GUIDELINES

Q. IS THE APPLICANTS' PROPOSAL CONSISTENT WITH THE GUIDANCE GIVEN BY THE COMMISSION?

A. Yes. As noted at several points above, the Applicants' proposal is guided by the Commission's recommendations in Order 2000 and in the Commission's 1992 Policy Statement on Incentive Regulation. Below is a list of the specific guidelines established by the Commission along with an explanation of how the incentive regulation provisions proposed herein conform to the guidelines. I have used nine specific criteria recommended by the Commission. These criteria are: [31]

(1) Incentive ratemaking must be prospective;

(2) Participation must be voluntary;

(3) Incentive mechanisms must be understood by all parties;

(4) Quality of service must be maintained;

(5) PBR should not be piecemeal;

(6) PBR should encompass both rewards and penalties;

(7) PBR should induce efficiency while preserving reliability;

(8) Benefits of PBR should be shared with customers;

(9) Rewards and penalties should be prescribed in advance.

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[31] The first four of these criteria are from the *Policy Statement on Incentive Regulation*, 1992, *op cit*. The remaining five criteria are from *Order 2000*, *op. cit*. As noted above, in its 1992 Policy Statement, the Commission also required that benefits to customers be quantifiable. In subsequent policy findings, the Commission has eliminated this requirement. See *Statement of Policy and Request for Comments*, *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, Docket No. RM95-6-000 and *Regulation of Negotiated Transportation Services of Natural Gas Pipeline*, RM96-7-000 (January 31, 1996), at 46.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT INCENTIVE RATEMAKING BE PROSPECTIVE?

A. Yes. The Commission's Policy Statement on Incentive Regulation recommended that incentive rate making be prospective in that it must reward future action, not past behavior. Hence, rates should be designed to reward future cost savings. The Applicants' PBR proposal satisfies this principle. First, the rate cap is based on current cost-of-service rates and only the O&M component increases (in accordance with CPI-0.5%). To the extent the Applicants can achieve cost savings which cause costs to grow more slowly than this, they will be able to enjoy the benefit of the plan. This creates a strong incentive for future efficiency improvements and produces the effect intended by the Commission's principle. Second, the plan to share one-half of the A&G savings with customers is also prospective, as it is based on savings in future years. It also creates similar incentives for efficiency as the O&M rate cap, because one-half of the future cost savings are retained by the Applicants.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT PARTICIPATION IN INCENTIVE RATEMAKING BE VOLUNTARY?

A. Yes. This principle is met by tautology in this case because the Applicants are proposing this incentive regulation plan themselves. In the Policy Statement, the Commission recognized that utilities face differing market conditions, favoring a policy that makes incentive rates voluntary.[32] But the Commission recognized that utilities also

[32] *Policy Statement on Incentive Regulation*, 1992 *op cit*. at 11.

should not just abandon their plans when profits decline. Accordingly, the Applicants commit to retaining the rate cap for the entire rate cap period and can only suspend it with Commission approval. This prevents the Applicants from abandoning the plan in light of any difficulty in achieving actual cost reductions.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT INCENTIVE MECHANISMS BE UNDERSTOOD BY ALL PARTIES?

A. Yes. The Commission's Policy Statement on Incentive Regulation recommended that incentive ratemaking be understood by all parties. The Applicants' proposed incentive regulation plan will do this because it is straightforward. The rate cap is simple: rates are frozen at cost-of-service levels except for the O&M portion which increases in accordance with a simple adjustment factor based on the CPI, the most widely-understood price index. The sharing of A&G cost savings is also simple: rates will be adjusted to reflect a 50% savings of each year's A&G costs.

Finally, incentive regulation on incremental investments is not complex– addressing only two types of investments: those that either enhance reliability or provide system benefits and those undertaken on a discretionary basis. This distinction would be determined by the RTO. The treatment of each type of investment is also straightforward – incentive-adjusted embedded costs for investments requested to enhance reliability and/or provide system-wide benefits and market-based treatment for directly assigned investments. Finally, the purpose of this filing is in part to explain this incentive rate proposal and receive guidance from the Commission prior to filing the full rate case. Hence, this filing itself stands as an effort to satisfy this principle.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT QUALITY OF SERVICE BE MAINTAINED?

A. Yes. The Commission's Policy Statement on Incentive Regulation recommended this principle. Pursuant to this, the Applicants propose to initiate a collaborative process among stakeholders to develop benchmarks that will ensure service quality and reliability. Additionally, the Applicants' plan allows recovery of incremental plant cost during the rate cap period, which aids in ensuring that necessary investments are undertaken that maintain system-wide service quality.

The Commission has acknowledged that these proposals can be complex and are best developed with substantial stakeholder involvement. The Applicants' proposed process achieves these objectives and provides time for the Applicants to gather data under its initial operations to inform development of the benchmarks. Nevertheless, consistent with their obligation to customers, the Applicants intend to maintain high quality of service.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT INCENTIVE REGULATION NOT BE PIECEMEAL?

A. Yes. In Order 2000, the Commission established that incentive ratemaking should not be piecemeal. The Commission explained that both costs and performance should be addressed and that all costs should be addressed, both short-term and long-term. The Applicants' proposal satisfies this principle. First, the specific proposals advanced by the Applicants in this filing are cost related. The Applicants commit to developing a benchmarking system together with stakeholders to address quality-of-service issues. Hence, both costs and operations are addressed. Second, the cost-related provisions address both short-term and long-term costs. The rate cap applies to the entire rate, even though the rate adjustment is only applied to the O&M portion of the rate (i.e., the balance of the rate is subject to the rate moratorium). This rate cap is intended to provide incentives to reduce costs over the short-term. In addition, specific provisions are included to address new investment going forward to provide incentives to improve efficiency with respect to long-term costs.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT INCENTIVE REGULATION SHOULD ENCOMPASS BOTH REWARDS AND PENALTIES?

A. Yes. This principle was established in Order 2000. The incentive plan satisfies this both with respect to the rate cap and with respect to the incentives to invest in new capital. With respect to the rate cap, the Applicants are rewarded if they can attain O&M cost savings that cause the O&M portion of rates to rise more slowly than the CPI-0.5% adjustment factor. However, if the Applicants' O&M costs rise more quickly than the CPI-0.5% adjustment factor, then the Applicants will be penalized because the cap will not fully reflect the actual cost increases. In addition, the Applicants intend to develop a benchmarking proposal that would include additional incentives for exceeding the benchmarks and penalties for failing to perform up to the level of the benchmarks. The Applicants are further rewarded to the extent they undertake new investments in system-wide improvements, something the Commission has emphasized as a key goal in Western power markets. This reward is in the form of a 200-basis points incentive-adjusted return for new investments. Of course, if such new investments are not prudent, the investment can be disallowed as a penalty, as is the case in all cost-based regulatory regimes.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT INCENTIVE REGULATION SHOULD INDUCE EFFICIENCY WHILE PRESERVING RELIABILITY?

A. Yes. In Order 2000, the Commission established that incentive proposals should not distort decision making with respect to the operation of and the investment in the grid. The rate cap provides strong short-term incentives to reduce costs and increase efficiency through more efficient use of O&M inputs. However, the benchmarks that are proposed to be developed in a collaborative process will help ensure quality of service with respect to operations.

With regards to efficient investments, the incentive-adjusted return-on-equity helps ensure that system-wide improvement will be undertaken. Furthermore, as discussed in some detail above, the incentive to favor transmission solutions over generation solutions will be severely undercut by the fact that such suboptimal actions will reduce overall grid usage, resulting in lower rate revenues. Furthermore, TransConnect will not be able to deny reasonable requests to interconnect to the grid. Finally, the Applicants are committed to meeting their obligation to sustain high standards of reliability.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT BENEFITS BE SHARED WITH CUSTOMERS?

A. Yes. Order 2000 requires this. The Applicants' proposal satisfies this principle by establishing a rate cap that is proposed to increase much more slowly than anticipated cost increases. In addition, customers will receive 50 % of the A&G savings during the rate cap period. These provisions are explicit mechanisms to share the efficiency savings with customers. Moreover, the rate cap plan related to O&M savings even guarantees lower rates in advance of any realization of any cost savings. This goes further than after-the-fact sharing mechanisms.

Q. DOES THE APPLICANTS' PROPOSAL MEET THE COMMISSION'S PRINCIPLE THAT REWARDS AND PENALTIES BE PRESCRIBED IN ADVANCE?

A. Yes. This principle was articulated in Order 2000 and the Applicants' proposal satisfies this principle. First, the rate cap and other rate provisions are described in detail in the filing and my testimony above. The sharing of O&M efficiencies and A&G efficiencies are specific and fixed. The incentive-adjusted return is also specific and fixed. And the benchmarking provisions will also be fixed upon their completion in consultation with stakeholders. Hence, all elements of the plan are clearly indicated in advance, including rewards and penalties.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Avista Corporation;	)	
The Montana Power Company;	)	
Nevada Power Company;	)	Docket No. RT01-15-____
Portland General Electric Company; and	)	
Sierra Pacific Power Company	)	Docket No. ER01-___-000
	)	
TransConnect, LLC	)	(Not Consolidated)
	)	

DECLARATION

I, David B. Patton, am submitting testimony in the above-captioned proceeding to establish initial transmission rates for TransConnect, LLC. My business address is 4029 Ridge Top Road, Suite 350, Fairfax, Virginia. I submit this Declaration to verify that the Direct Testimony of David B. Patton filed in the above-captioned proceeding was prepared by me, with the assistance of others working under my direction and supervision, and that the contents thereof, and the attached exhibits are true and correct to the best of my knowledge, information and belief. I declare under penalty of perjury that the foregoing is true and correct. Executed in Fairfax, VA on the 31st day of October, 2001.

____
David B. Patton